ORIGINAL

E000021864

MEMORANDUM

TO: Docket Control

FROM: Elijah O. Abinah
Director
Utilities Division

DATE: October 21, 2022

RE: IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF A DISTRIBUTED DEMAND-SIDE RESOURCE AGGREGATION TARIFF AND SERVICE SCHEDULE. (DOCKET NO. E-01345A-22-0143)

SUBJECT: REVISED LAWRENCE BERKELEY NATIONAL LABORATORY REPORT

On September 30, 2022, Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff") docketed three reports submitted by Lawrence Berkeley National Laboratory regarding its evaluation of the Distributed Demand-Side Resource ("DDSR") Aggregation Tariff. On October 20, 2022, Lawrence Berkeley National Laboratory provided a revised report on the Estimated Load and Participant Cost Impacts. The revised report is attached.

EOA:RSP:elr/

Originator: Ranelle S. Paladino

Attachments

ACC - Docket Control - Received 10/21/2022 12:30 PM
ACC - Docket Control - Docketed 10/21/2022 1:48 PM

On this 21st day of October, 2022, the foregoing document was filed with Docket Control as a Utilities Division Memorandum, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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ATTACHMENT

BERKELEY LAB

Electricity Markets and Policy Department

October 20, 2022

To: Eli Abinah, Ranelle Paladino, Barbara Keene and Ryan Kern, Arizona Corporation Commission

From: Jeff Deason, Chandler Miller, Lisa Schwartz, JP Carvallo and Sunhee Baik

Subject: Estimated load and participant cost impacts for Arizona Public Service's battery aggregation products under its filed Distributed Demand-Side Resources tariff

At its open meeting on February 18, 2021, the Arizona Corporation Commission approved Lawrence Berkeley National Laboratory (Berkeley Lab) to provide technical assistance to Commission Staff on the Distributed Demand-Side Resources (DDSR) Aggregation Tariff to be filed by Arizona Public Service (APS). Among other areas of assistance, Berkeley Lab estimated utility load impacts and participant cost impacts of proposed battery aggregation products for Product A (capacity) and Product B (locational value) for several categories and locations ("cohorts") of APS customers.

This memo summarizes our methodology and modeling results. Appendices provide additional details:

- Appendix A - detailed parameters for calculations
- Appendix B - data sources, assumptions and methods for estimating resilience benefits

An accompanying slide deck provides detailed results for load and cost impacts for each cohort of households we modeled.

Modeling methodology

Data

We requested and received the following data from APS for cohorts of households, chosen at random and anonymized:

- 100 homes with existing solar in the Phoenix area (Cohort A)
- 100 homes with existing solar in the Flagstaff area (Cohort B)
- 100 homes with existing solar in the Yuma area (Cohort C)
- 100 homes without existing solar in the Phoenix area (Cohort D)

- 100 homes without existing solar in the Flagstaff area (Cohort E)
- 100 homes without existing solar in the Yuma area (Cohort F)

Data received for each household included:

- Hourly electricity consumption for the 2021 calendar year
- For households with existing solar, PV generation and export data for the 2021 calendar year
- Electricity rates and riders for each household

System configurations

The DDSR tariff required by the Commission does not include solar PV, and solar PV will not receive any incentive under the tariff. Further, under the proposed battery aggregation program, the batteries will not charge from the grid or discharge directly to the grid. Therefore, we model solar + storage systems.

For households with existing solar PV systems, we modeled the impact of adding battery storage, using operating modes for the selected aggregator and technology — Generac PWRCell batteries. For households without existing solar PV systems, we modeled the impact of adding both solar PV and battery storage. We did not model stand-alone storage scenarios for households without existing PV.[1]

For households without existing PV, we modeled the impact of two PV system sizes. We modeled an 8.25 kW system, the size of the median residential PV system in Arizona in 2020 based on the most recent data available.[2] Based on initial test modeling, we found that some households — especially in Flagstaff, where loads are lower — had better economic outcomes from a smaller and less expensive PV system, so we also modeled the 20th percentile[3] Arizona residential system size (5.76 kW) for each household as a separate scenario.

We modeled the addition of the four Generac PWRCell batteries available under the proposed aggregation product: 9 kWh, 12 kWh, 15 kWh, and 18 kWh. Detailed specifications for these batteries are in Appendix A.

Rates and riders

All APS PV customers are served on time of use (TOU) rates. The installer will program the batteries to operate based on the customer's selected rate option.

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[1] Stand-alone storage is rare in residential buildings. The passage of the Inflation Reduction Act, which makes the investment tax credit available for stand-alone storage, may change this somewhat. However, the operating modes of the Generac PWRCell batteries largely presume the presence of solar. Moreover, our modeling results show that solar PV is also economically beneficial to most APS households who would benefit from storage, so we would expect the vast majority of customers without prior solar PV will install it when installing storage.

[2] See https://emp.lbl.gov/tracking-the-sun.

[3] The Tracking the Sun dataset lists the 20th, 50th, and 80th percentile system sizes for most stares, including Arizona.

In accordance with requirements of the proposed DDSR tariff and other APS tariffs, we modeled the following rate and rider options:

- *Households with existing solar* that participate in net metering may stay on their legacy TOU rate or switch to the resource comparison proxy export rate rider for solar compensation and one of two newer TOU rate options:[4]
    - R-TOU-E, with a 4-7 pm peak period on weekdays
    - R-3, with a 4-7 pm peak period on weekdays and a demand charge defined by the highest hour of usage each month within the peak period
- *Households without existing solar* may transition to either of these two TOU options.

System technical parameters and costs

For solar PV, we used default technical parameters from PVWatts, an industry standard software package. We used Berkeley Lab's Tracking the Sun dataset (Barbose et al. 2021) for installed costs of solar PV systems.

We draw the roundtrip efficiency of the Generac PWRCell batteries from Generac's PWRCell datasheet.

We use the manufacturer's suggested retail price (MSRP)[5] of the Generac batteries as the installed cost of the systems, without any explicit adjustments for installation costs, costs of any other necessary components, or vendor financing. This cost estimate is somewhat uncertain. A recent review of PWRCell batteries estimates $2,000 in installation costs.[6] However, that same article notes an installed cost range for the PWRCell batteries of $11,500-$17,000 – which is actually below the MSRP ranges of the available battery options. (MSRPs do not include installation costs.)

Tables A1—A4 in Appendix A show the values we used for technical parameters and costs for solar and storage systems.

Solar generation modeling

For households without existing solar, we used PVWatts to model the electricity production of the added solar PV system in each of the three cohort locations (Phoenix, Flagstaff, Yuma). Households with existing solar required no solar modeling; we used the PV generation and dispatch data provided by APS.

[4] Rates and riders can be downloaded at https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors. Two other time-of-use rates, with 3-8 pm peak periods, are available; however, the tariff sheets for these rates indicate that customers served under those tariffs will be transitioned to a 4-7 pm peak period rate.
[5] APS supplied Berkeley Lab with the MSRPs by email on August 1, 2022.
[6] See https://www.solarreviews.com/blog/generac-power-cell-expert-review.

Storage dispatch modeling

We created a storage dispatch model that implements the relevant operating modes of the Generac PWRCell battery:[7]

- *Clean Backup mode*: battery charges from excess solar PV generation when available
- *Self Supply mode*: battery discharges to offset net load — that is, load remaining after solar generation — or charges from excess solar when available
- *Sell mode*: battery discharges to offset net load

Outside of called demand response events, we model the batteries in Clean Backup mode during off-peak hours and in Self Supply mode during peak hours.

We model the batteries in Sell mode during summer event calls. APS can call summer events between 3 pm and 8 pm on weekdays or weekends. On weekday events we assume that event calls begin at 4 pm and end at 8 pm. We chose a 4 pm start because APS may seek to avoid 3 pm event calls. For a customer on a TOU rate with a 4-7 pm peak period, calling an event at 3 pm would discharge the battery during the off-peak period, potentially resulting in insufficient battery reserves to offset peak period consumption. Weekend events begin at 3 pm, since APS's TOU rates do not have weekend peak periods and there is no risk of displacing peak period discharge during an event.

During winter event calls, we assume that the aggregator sets the batteries to Sell mode at midnight before the event is called. Batteries discharge to offset load during the middle of the night, making space to charge from excess solar to mitigate systemwide overproduction of solar during the 10 am-2 pm low-load event window. Setting the batteries at Sell mode earlier the prior evening could create additional space and allow for greater charging during the event window; setting Sell mode later would create less space and enable less charging during the event. The batteries operate in Clean Backup mode during winter events.

We use the maximum number of events APS specified for each product: 20 events for Product A; 60 summer events and 80 winter events for Product B. In order to observe impacts on both weekdays and weekends, and because the incremental impact of summer weekend events is much larger than summer weekday events, we modeled half of the summer events to occur on weekends for each product, with the remainder on weekdays. We define event days by referencing ABB Ventyx VelocitySuite data[8] and choosing the days with the highest system lambdas in the case of summer events, or the lowest system lambdas in the case of winter events.

[7] See https://www.generac.com/service-support/pwrcell-homeowner-resources/pwrcell-faq for more information on PWRCell operating modes.

[8] 2021 system lambda data for Arizona Public Service can be accessed using ABB's Ventyx Velocity Suite portal: https://www.hitachienergy.com/us/en/offering/product-and-system/energy-planning-trading/market-intelligence-services/velocity-suite.

We assume that batteries are never charged from the grid, only from the customer's excess rooftop solar generation.[9] Based on APS's stated intentions, we assume that batteries are never discharged directly to the grid, only to offset customer load.[10]

Customer bill and cost impacts

We considered all possible combinations of solar PV, battery storage sizing, and rate/rider options for the households in each cohort described above. We assume each household will select the system and rate/rider combination that yields the lowest net present value (NPV) of its electricity costs over 25 years.[11] NPV accounts for upfront system costs, ongoing electricity bill costs, and operations and maintenance costs of the system, including battery replacement costs, and applies a discount rate to value these costs over time.

Appendix A provides details on the parameters used for our NPV calculations.

Value of solar plus storage systems for reliability and resilience

We estimate the reliability and resilience value of solar plus storage systems using a framework developed by Berkeley Lab.[12] Resilience benefits (for service interruptions of more than 24 hours) are based on the ability of a solar system with a 10 kWh battery to mitigate individual interruptions with durations ranging from one to 10 days.

We first determine load that would be lost during an interruption of a given duration. Second, we leverage results from an ongoing Berkeley Lab project[13] to estimate the load that the solar plus storage would meet. We monetize the unmitigated and the mitigated lost load and define the difference as the resilience benefit. Monetization is based on a Value of Lost Load (VOLL) of between $7/kWh and $8.30/kWh (depending on duration), calculated from a recent survey of long duration interruption costs conducted in another state. We use OE-417 form data[14] on long duration interruptions to estimate the frequency of interruptions of durations ranging from one to 10 days in Arizona and neighboring states. We use these frequencies to estimate expected benefits for each duration and add them up for an annual resilience benefit. Given their uncertainty and impact on results, we use a low and a high set of frequencies. Results show benefits of $152-$249/yr. for Flagstaff, $234-$385/yr. for Phoenix, and $260-$423/yr. for Yuma.

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[9] Prior to the Inflation Reduction Act, households with solar plus storage generally avoided charging batteries from the grid to take advantage of the Investment Tax Credit for storage, which was sharply reduced by even small amounts of grid charging. While passage of the Act changes this incentive, the PWRCell and other battery storage systems are currently still designed around the assumption that customers charge their batteries from excess solar. We maintain this assumption in our modeling.

[10] Per our August 3 discussion with APS.

[11] We use a 25-year period to match the typical life of a solar PV system. Battery lifetimes are shorter, and we assume that customers replace their batteries after ten years. Details of equipment lifetimes and costs are in Appendix A.

[12] *"Evaluating the Capabilities of Behind-the-Meter Solar-plus-Storage for Providing Backup Power during Long-Duration Power Interruptions,"* expected to be released in early October 2022.

[13] *Ibid.*

[14] See https://www.oe.netl.doe.gov//oe417.aspx.

We calculated reliability benefits (for service interruptions of less than 24 hours) assuming that the solar plus storage system can fully mitigate the short-duration interruptions that are covered in this analysis. We use data from Form EIA-861[15] to calculate a four-year average of the System Average Interruption Duration Index (SAIDI) for APS, which describes the average annual time without power for a customer in a utility territory. Using data from the resilience analysis, we calculate the annual lost load and value its mitigation using the same VOLL. Given the relatively low SAIDI in Arizona – between one and two hours per year – the reliability benefits are much smaller: \$14/yr. for Flagstaff, \$25/yr. for Phoenix, and \$29/yr. for Yuma. Appendix B provides details for data sources, assumptions, and methods for our estimate of reliability and resilience benefits.

Modeling results

Key takeaways from our modeling include the following:

- *Peak load reduction* - Participants in battery aggregation products A and B would reduce their peak period loads substantially during weekdays, even when demand response events are not called, under APS's TOU rates. Calling events on summer weekdays would yield small additional load reductions. Event calls on summer weekends would have a greater incremental impact on load reductions, since batteries would otherwise not discharge at all on those days because the TOU rates do not have peak periods on weekends. Product B non-summer event calls also have large incremental impacts on net load. They significantly increase battery charging during the event window and therefore export less excess PV generation to the grid.
- *Cost impacts for participants* - About 18% of Phoenix-area households who do not currently have solar would financially benefit from participating in Product A and installing new solar plus storage systems — in other words, the net present value (NPV) of the change in their electricity costs over a 25-year period[16] is positive. About 6% of Phoenix-area households without solar today would financially benefit from participating in Product B and installing new solar plus storage systems. When we include the value of the reliability and resilience benefits offered by these systems, we estimate that 66% of Product A customers and 50% of Product B customers would benefit.
- *Net metering customers* - Customers with existing solar PV systems who are on grandfathered rates and the grandfathered net metering rider will generally not financially benefit by adding storage and participating in the battery aggregation products. These rate structures do not yield large benefits from storage, and switching to other rate structures would require customers to abandon the net metering rider.

[15] See https://www.eia.gov/electricity/data/eia861/.
[16] 25 years is a common assumption for the lifetime of a solar PV system, and is the default system lifetime assumption in the ReOpt model, from which we draw many of the parameters used in our analysis (see Appendix A).

Load impacts

The battery aggregation products would impact customer loads on both non-event and event days. The batteries reduce load every weekday during peak TOU periods, year-round. During summer weekday events, from 4 pm to 8 pm,[17] the batteries reduce:

- 85% of net household load for NPV-positive Product A customers in Phoenix who add solar plus storage systems
- 78% of net household load for NPV-positive Product B customers in Phoenix who add solar plus storage systems

During non-event summer weekdays, the batteries reduce 96% of net load during the 4-7 pm TOU peak period for those same Product A participants.

Tables 1 and 2 summarize our modeling of storage load impacts[18] for APS customers living in Phoenix who install *new* solar plus battery storage systems to participate in battery aggregation for Product A (summer load reduction from 3-8 pm) and Product B (summer load reduction from 3-8 pm and non-summer load deployment from 10 am-2 pm, available to customers on six targeted feeders in the Phoenix area).

Table 1. Product A load impacts for Phoenix customers installing new solar + storage systems

	Summer load reduction (kWh per participant), 3-8 pm			
	Weekday		Weekend	
	All	+ NPV	All	+ NPV
Product A, no event	4.5	5.5	0.0	0.0
Product A, event	5.8	8.6	6.0	8.3

Table 2. Product B load impacts for Phoenix customers installing new solar + storage systems

	Summer load reduction (kWh per participant), 3-8 pm				Non-summer load increase (kWh per participant), 10 am-2 pm			
	Weekday		Weekend		Weekday		Weekend	
	All	+ NPV	All	+ NPV	All	+ NPV	All	+ NPV
Product B, no event	4.3	5.3	0.0	0.0	1.3	1.7	1.3	1.5
Product B, event	5.5	8.4	5.5	7.3	5.7	7.1	5.5	6.6

[17] Events may be called beginning at 3 pm; however, as noted in the methodology section below, we assume weekday events are called beginning at 4 pm to avoid forcing dispatch outside of the TOU peak period of 4-7 pm.
[18] For customers installing new solar plus storage systems, solar generation would also significantly change the customer's load during (and outside of) events. Because solar PV is not part of the DDSR tariff, Tables 1 and 2 include only the impacts of storage.

The "All" case in Tables 1 and 2 is the average load reduction impact for all modeled households who might participate in the program for any reason — e.g., for resilience during utility outages or to maximize consumption of self-generated solar electricity. The "+ NPV" case is the average load reduction impact only for households that would see lower electricity costs over a 25-year period (positive-NPV customers). We assume that households who would experience positive economic outcomes would be more likely to participate, but that customer economics will not fully explain participation. Customers with positive NPV generally have larger loads and offer a greater grid resource, as Tables 1 and 2 show. Therefore, the "All" and "+ NPV" cases likely bound actual outcomes.

In the maximum NPV cases in our simulation, customers with positive NPV generally have larger batteries (which can be supported by their larger loads), explaining the greater grid resource they offer. NPV-positive customers choose a mix of 9, 12, and 18 kWh batteries. (Very few customers would choose 15 kWh batteries, since the higher incentive for 18 kWh batteries makes them comparable in customer cost to the 18 kWh batteries.) Most customers who are not NPV-positive see their best financial outcomes with 9 kWh batteries since these batteries are the least expensive.

Because peak demand reduction on non-event days occurs through battery dispatch programmed in response to APS's TOU rates, calling events on summer weekdays will have relatively little incremental impact on total load shed. Since APS's time-of-use rates do not include weekend peak periods, the batteries will not discharge on weekends during ordinary operations. Therefore, the incremental impact of event calls on summer weekends is considerably larger. While batteries will charge somewhat during the low-load event window of 10 am-2 pm during non-summer periods, non-summer events also will have a relatively large impact on load deployment. Our assumption that batteries go into Sell mode at midnight before a non-summer event call has a significant impact in our results. If the aggregator moves batteries into Sell mode earlier in the evening before the event, non-summer event impacts would be larger.

Figures 1-4 visualize the load impacts of solar generation and storage dispatch for Phoenix households that do not have existing rooftop solar. A large share of APS customers live in the Phoenix area and, as we show below, the economics of participation are generally stronger for customers who did not previously have solar than those who did. Further, Product B is not available outside of Phoenix.

Figure 1. Product A - "All" case load impacts for Phoenix customers installing new solar + storage systems

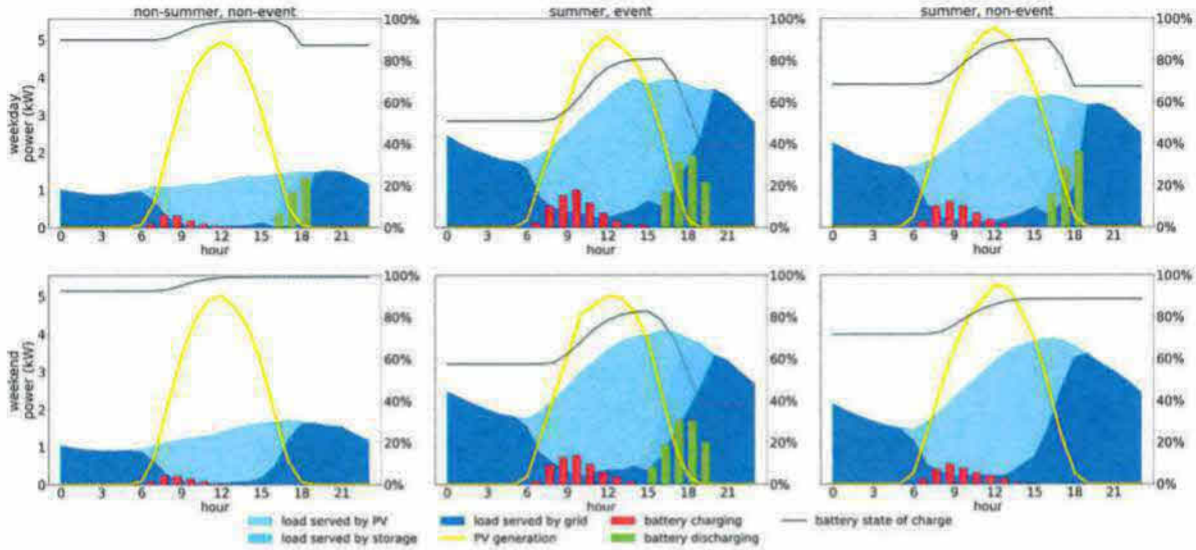


Figure 2. "+ NPV" case Product A load impacts for Phoenix customers installing new solar + storage systems

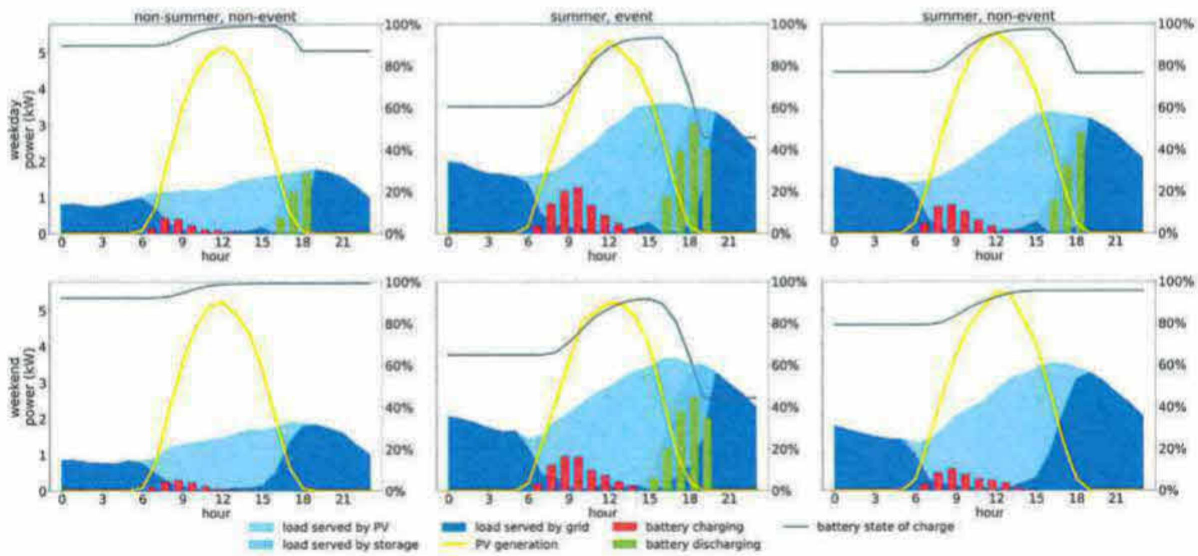


Figure 3. "All" case Product B load impacts for Phoenix customers installing new solar + storage systems

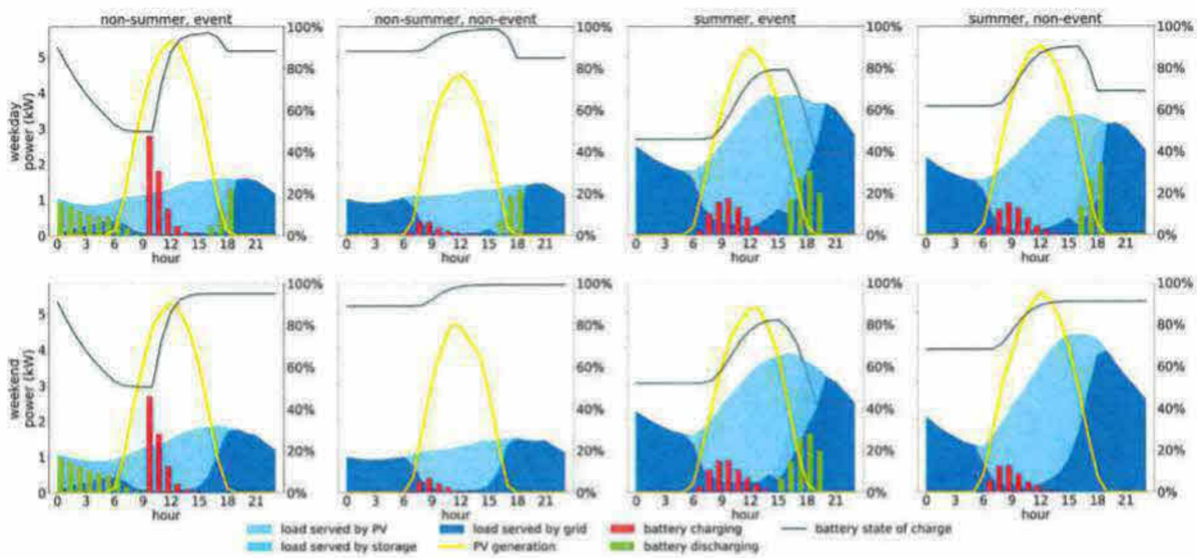
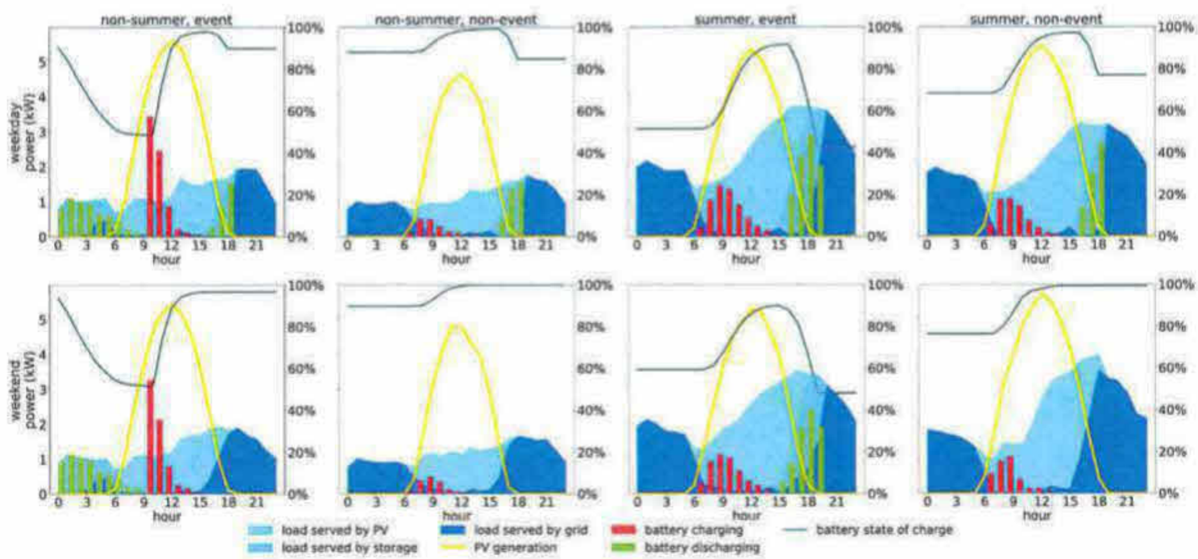


Figure 4. "+ NPV" case Product B load impacts for Phoenix customers installing new solar + storage systems



We also modeled load impacts for customers in Yuma and Flagstaff. For Product A, load impacts for customers in Yuma are broadly similar to impacts for customers in Phoenix. Customers in Flagstaff offer less load impact, both in summer and in winter, given their lower electricity consumption in general. Similar figures for these Yuma and Flagstaff households are in the accompanying slide deck.

In addition, we modeled impacts for customers in all three locations that add storage to existing solar PV systems. Customers in Phoenix with pre-existing solar generally offer less peak-period load reduction, largely due to their legacy rate structure (TOU rates with a 12-7 pm or 9 am-9 pm peak period on weekdays). If configured to match those legacy peak periods (as we assume), the batteries would dispatch much of their capacity earlier than 4 pm, the start of the peak period under APS's newer TOU rates. As a result, customers with pre-existing solar would offer less load reduction during system peak periods, both during and outside of events. This behavior is readily visible in the Cohort A load results in the accompanying slide deck, since a large share of Cohort A — Phoenix customers with existing PV — is on grandfathered rates. The same applies to customers with pre-existing solar in Flagstaff (Cohort B) and Yuma (Cohort C), though to a somewhat lesser extent since fewer of the Flagstaff and Yuma households in our sample are on grandfathered rates. Similar figures for these households are in the accompanying slide deck.

Participant cost impacts

Based on our assumptions and calculations, 18 of the 100 Phoenix households we studied without existing PV systems would benefit financially from Product A, as measured by the NPV of their electricity costs over a 25-year period. These households would have lower 25-year electricity costs with solar plus storage systems than (a) their current electricity costs or (b) their costs if they adopted solar only and no battery storage. In Yuma 19 of 100 households without existing PV systems and in Flagstaff nine of 100 of such households would benefit financially from participating in Product A.

Product B is somewhat less financially attractive than Product A. Six of the 100 Phoenix households we studied without existing PV systems would benefit financially from participating in Product B.

Every household that benefits financially from participating in either product switches to the R-3 rate in our simulation. That rate has a 4-7 pm peak period and demand charges for that period. These customers would use their batteries to significantly reduce and, in many cases, eliminate their demand charges. While customers do not always select their lowest-cost rate structure, we anticipate that most customers participating in either product would choose the R-3 rate.

Based on our modeling, households with *existing* PV systems on the grandfathered net metering rider and grandfathered TOU rates will not save money from participating in Product A or Product B. Our modeling suggests that solar PV customers would see their costs go up if they switched rate structures, and adding battery storage is not economically attractive on their current rate structures. (None of the grandfathered rates have demand charges.) However, existing solar PV customers would still receive resilience benefits of the battery.

- None of the households in Phoenix with existing solar would see their 25-year electricity costs go down when adding storage and participating in Product A or Product B. This is in significant measure because most of the Phoenix households with existing solar whose load data we received are on grandfathered rates and riders (net metering).

- Four of 90 households in Flagstaff with existing solar, and seven of 96 households in Yuma with existing solar, would benefit from participating in Product A based on our modeling assumptions (however, see the next bullet). None of these households are on grandfathered rates.
- Our cost calculations do not factor in any additional costs for reconfiguring existing PV systems to add storage. As a result, even fewer households with existing solar PV systems might have cost-positive outcomes than our modeling suggests.

Reliability and resilience value

Solar and storage systems offer non-monetary value by providing power in the event of a service interruption. Based on Berkeley Lab research, we estimate that APS customers would be willing to pay between \$2,000 and \$6,000 for these reliability and resilience benefits. Accounting for these benefits, the number of customers who would see positive value from solar plus storage under this program would be higher than stated above. For example, in Phoenix at least 66% of households without existing solar would see positive value from Product A when accounting for reliability and resilience benefits, while only 18% see positive value without them. At least 50% of these same Phoenix households would see positive value from Product B when accounting for these benefits, while only 6% see positive value without them.

We do not find that customer economics pose a challenge for fulfilling Product A objectives. However, we would expect that households who do see positive value will be more likely to enroll than those who do not. Given that 18% of Phoenix households without existing PV see positive economic value — and many more might find participation worthwhile when considering reliability/resilience value — we expect that APS and Generac will be able to find enough customers who would benefit from participation to deliver their Product A objectives.

We are less sure that customer economics will not pose a challenge for fulfilling Product B objectives. Product B targets six specific feeders in the Phoenix area and is slightly less financially attractive than Product A. We do not know how many customers are on these feeders or their specific loads. APS and Generac will need to recruit a significantly higher fraction of these customers than they will for Product A, which is available to customers throughout APS's service territory.

Appendices

Appendix A. Model inputs

Table A-1. Financial parameters

Financial parameter		Source
Analysis years	25	ReOpt tool default values (NREL)
Annual electricity price escalation	1.9%	ReOpt tool default values (NREL)
Discount rate	5.67%	ReOpt tool default values (NREL)

Table A-2. Battery technical and cost parameters

Battery Configuration	Energy (kWh)	Power (kW)	MSRP ($)	Incentive ($)	Source
1	9	3.4	12,315	2,000	Energy and power from Generac inverter and battery data sheet MSRP and incentives provided by APS
2	12	4.5	14,264	2,000	
3	15	5.6	16,213	2,000	
4	18	6.7	18,162	4,000	

Table A-3. PV system technical and financial parameters

PV (applies to cohort without pre-existing solar only)		Source
Azimuth	180°	ReOpt tool default values (NREL)
Tilt	19°	Tracking the Sun (LBNL)
DC:AC ratio	1.2	ReOpt tool default values (NREL)
Location	roof-mounted	ReOpt tool default values (NREL)
Losses	14%	ReOpt tool default values (NREL)
PV inverter efficiency	96%	ReOpt tool default values (NREL)
PV Installed cost ($/kW$_{DC}$)	3763	Tracking the Sun (LBNL)
O&M cost ($/kW-year)	16	ReOpt tool default values (NREL)
Arizona solar tax credit ($)	1000	AZ Department of Revenue
Investment tax credit	30%	Inflation Reduction Act of 2022

Table A-4. Battery storage technical, cost, and operating parameters

Battery storage parameter		Source
Installed cost	See Table A-2, MSRP	Provided by APS
Replacement year	10	ReOpt tool default values (NREL)
Replacement cost ($/kWh)	308	2022 Annual Technology Baseline (NREL)
Replacement cost ($/kW)	238	2022 Annual Technology Baseline (NREL)
Roundtrip efficiency	90.80%	Generac inverter and battery data sheet
Initial state of charge	50%	ReOpt tool default values (NREL)
Battery reserve capacity	20%	Provided by APS
Maximum state of charge	100%	ReOpt tool default values (NREL)
Investment tax credit	30%	Inflation Reduction Act of 2022

Appendix B. Reliability and resilience value methodology

Storage dispatch model

We used a storage dispatch model to determine the estimated capability of solar plus storage systems to sustain load during an outage. The model dispatches storage to meet the load profile inputs during simulated outages.[1]

Berkeley Lab designed the model to estimate long-duration backup capabilities, with outages from 1 to 10 days in 24-hour increments. To estimate mitigation potential for an event, an outage is applied at 12 am for one median net load day (i.e., net load after applying solar generation) per month. Solar generation profiles are based on the National Renewable Energy Laboratory's (NREL's) System Advisor Model, and systems are sized to meet 100% of annual building energy consumption. All simulations use storage sizing of 10 kWh, 5 kW. Load profiles are single-family detached building models from NREL's ResStock database.

We modeled buildings in hourly intervals using regional weather data and building characteristics. We used the single-family building type for each county in Cohorts A-C: Maricopa, Coconino, and Yuma. While the model is capable of shedding non-critical loads, we modeled the capability of solar plus storage systems to meet total load without any load shedding.[19]

[19] Additional details on calculating mitigation potential will be available in Berkeley Lab's forthcoming report, *Evaluating the Capabilities of Behind-the-Meter Solar-plus-Storage for Providing Backup Power during Long-Duration Power Interruptions*, expected to be released in early October 2022.

For long duration calculations, the amount of load shed for each simulated outage, as well as total expected load, came directly from the model. For short duration calculations, we calculate the average hourly load per month directly from net load profiles.

Inputs for reliability events

The Energy Information Administration (EIA) collects information annually on utility operations, including sales, revenue, generation, fuel consumption, and reliability, through EIA form 861. For this analysis, we used the System Average Interruption Duration Index (SAIDI) values reported by APS in EIA form 861 filing with and without major events (as defined by IEEE Standard 1366).

As a cross-check, we used the PoweroutageUS dataset, which tracks power interruption data on utilities' public-facing websites at an hourly level. This dataset includes the number of customers tracked and affected at the hourly and county/utility level. Thus, it is more granular than EIA-861 data. We extracted from the PoweroutageUS dataset data for FIPS regions 4005, 4013, and 4027 (Coconino, Maricopa, and Yuma) for the time period December 2017 to November 2021 and calculated monthly SAIDI results for each county.[20] We use the relative monthly distribution to allocate APS's annual SAIDI to each month, and then calculate reliability benefits based on load lost at the monthly level.

Inputs from Form OE-417 major incident reports

To determine the number of long-duration power interruptions that affected Arizona, neighboring states (CA, NV, UT, CO and NM), and the rest of the Southwest United States, we used the Electric Emergency Incident and Disturbance Report collected through form OE-417. We developed a list of *distinct* major electric emergency incidents and disturbances[21] that:

1. occurred between 2000 to 2021,
2. directly resulted in losses to customers (demand loss or number of affected customers is greater than zero), and
3. required six or more hours to fully restore the power.

We then binned the events in one-day increments, with the first bin recording events from 6 to 24 hour duration, and subsequent bins in 24 hour blocks. We counted the number of events in each bin for Arizona and neighboring states. A key limitation of the data is that 21 years is not enough time to capture a representative sample of events that may occur every 50 years or longer. We use neighboring states to increase representation. There are many ways to incorporate information on events occurring in neighboring states. To serve as bookends, we selected two methods that produce a low and a high frequency of events. For low frequency

[20] The annual SAIDI figures are different from EIA-861 data due to incorrect total counts of customers in the Poweroutages.US data. However, the relative monthly distribution is correct.

[21] If there were several reports filed for a single reason, such as a wind storm, we merged those events into one event.

events, we incorporated 4% of neighboring states' events to produce a frequency of very long duration (>6 days) events — one event every 500 years, a conservative value. For high frequency events, we incorporated 10% of events in neighboring states to capture the portion of events that, on average, would occur relatively close to the Arizona border, given the size of neighboring states. This approach produces a frequency of very long duration events of about one event in 200 years, which is also consistent with the academic literature on reliability events.

Inputs for value of lost load (VOLL) calculation

U.S. utilities have conducted surveys of their customers to estimate customer interruption costs (CICs). Electricity customers can be segmented into four classes based on their consumption characteristics and the magnitude of interruption impacts they experience. Extending the efforts of utilities, Berkeley Lab and Resource Innovations, Inc. (formerly Nexant, Inc.) aggregated a large number of utility-sponsored CIC studies to estimate CIC functions for general use in utility planning (Lawton et al., 2003[22]; Sullivan, Mercurio, and Schellenberg, 2009[23], Sullivan, Schellenberg, and Blundell, 2015[24]).

The meta-analysis and econometric models serve as the basis for the Interruption Cost Estimate (ICE) calculator. The ICE calculator can estimate CICs based on utility characteristics, outage characteristics, and other conditions. However, the ICE calculator was originally intended to estimate costs for short and localized power interruptions; thus, it is not appropriate for determining the cost-effectiveness of solar plus storage systems during resilience events.

To the best of our knowledge, there have been no comprehensive studies estimating the economic impacts of power interruptions ranging from short and localized events to widespread and long-duration events in Arizona. For our analysis, we used direct and indirect power interruption cost estimates from a recent residential customer survey. These estimates sum up costs incurred due to the outage for interruptions lasting several days during summer or winter.[25] We used the elicited power interruption costs, divided by the average annual electricity consumption (i.e., \$/kWh estimates for energy not served), to estimate duration-dependent customer damage functions.

[22] Lawton, L., Sullivan, M., Van Liere, K., Katz, A., and Eto, J. (2003). A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys. https://emp.lbl.gov/publications/framework-and-review-customer-outage.
[23] Sullivan, M. J., Mercurio, M., and Schellenberg, J. (2009). Estimated value of service reliability for electric utility customers in the United States (No. LBNL-2132E). Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/estimated-value-service-reliability.
[24] Sullivan, M. J., et al. (2009).
[25] In this analysis, we excluded the top 10% of responses from the customer damage function.